UNITED STATES
DEPARTMENT OF AGRICULTURE
RURAL DEVELOPMENT

RURAL UTILITIES SERVICE

SUMMARY OF ITEMS OF ENGINEERING INTEREST
OCTOBER 2010

TABLE OF CONTENTS

ABBREVIATIONS

AMI	Automated Metering Infrastructure
AMR	Automated Meter Reading
ANSI	American National Standards Institute
BES	Bulk Electric System
CAD	Computer Aided Drafting
CIP	Critical Infrastructure Protection
DLH	Distribution Line Hardening
EC	Electric Cooperative
ECA	Electric Cooperative Association
EMC	Electric Membership Corporation
EPA	Electric Power Association
ESD	Electric Staff Division
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
IEEE	Institute of Electrical and Electronics Engineers
IP	Informational Publication
MDCL	Maximum Designed Cantilever Load
MS	Modular Substation
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
NRD	Northern Regional Division
P&D	Paterson & Dewar Engineers, Inc.
PRC	Protection and Control
REA	Rural Electric Association
RUS	Rural Utilities Service
SCADA	Supervisory Control and Data Acquisition
SRD	Southern Regional Division
TOP	Transmission Operations
USDA	United States Department of Agriculture

ENGINEERING

An Alternative Approach to Constructing a Substation

There is an alternative approach to designing and constructing standard substations called the "Modular Substation (MS)" approach. Modular substations have been around for some time, but recently we have heard more news about this approach. One reason for this is that the modular substation approach makes it more cost effective and more appealing now when compared with traditional substation construction. Recent improvements in substation equipment technology and cost efficiencies in installation and energizing of a modular substation make it more popular than a traditional substation. Some utilities have benefited from the short time commissioning and flexibility that the modular substation approach offers in site selection.

A typical modular substation consists of all components, controls, wiring, transformers, reclosers, and regulators. All pre-assembled equipment is installed on a self-supporting steel base frame. All onboard protection, control, and automation devices are pre-wired and tested before delivery to the site. The module then would be ready for quick installation on the customer's concrete pier foundations. Site preparation is significantly reduced, and few work hours would be required to complete the installation. This approach has resulted in significant savings on site work, construction and commissioning time. Completion time for a modular substation usually is half of the time that is required to complete traditional substation construction.
In preparation of a MS project, the following advantages can be discussed with managers:

- Overall lower cost
- Reduce construction time in half
- Reduce the required land for MS installation
- Maximize Safety and security
- Create MS system that can be easily modified in the future
- Design MS that is acceptable by the City, State, and County architectural zoning requirements

Modular substation design uses a broad range of applications and provides installation flexibility, allowing it to be tailored to the utility's requirements and commissioned within a short time frame. The modular substation is an ideal solution for additions or replacement of existing substation. Many of industry's leaders in the substation business are now providing modular substation fabrication and installations.

If you would like more information or have any questions, please contact Theodore V. Pejman, Electrical Engineer, Transmission Branch, at 202-720-0999 or at Ted.Pejman@wdc.usda.gov.

Separation of Outdoor Oil-Insulated Transformers from Buildings and Other Equipment

Transformers generally contain the largest quantity of a combustible substance that is located in a substation. Therefore, special attention should be given to their location in relation to control buildings, other transformers, and other combustible substance filled equipment. Most fires related to oil insulated transformers occur as a result of a breakdown of insulation caused by overloads, switching or lightning surges, low oil level, moisture in the oil, combustible gas accumulation within the transformer tank, or failure of the insulating bushing. Potentially, such a fire could cause a considerable amount of burning oil to be expelled over a large area and an intense fire could follow. Therefore, the location of transformers in a substation should be of concern to the designer and engineer. Every possible attempt should be made to locate oil-filled equipment away from substation buildings, other equipment, possible fire hazards present in adjacent properties, and similar hazards.

Determination of the physical separation design is based on type and quantity of oil in the transformer, size of a postulated oil spill (surface area and depth), type of construction of adjacent structures, power rating of the transformer, fire suppression systems provided, and type of electrical relaying protection provided.

Subclause 4.4.1 of IEEE Standard 979, "IEEE Guide for Substation Fire Protection," states:

> "Transformers containing 2000 gal (7571 L) or more of insulating oil should be at least 20 ft (6.1 m) from any building. If these large oil-filled transformers are located between 20 and 50 ft (6.1-15.2 m) of a building, the exposed walls of the building should constitute, or be protected by, at least a 2-hour fire-rated barrier. The barrier should extend in the vertical and horizontal directions such that any point of the transformer is a minimum of 50-ft (15.2 m) from any point on the wall not protected by the barrier. Should it be necessary to encroach on the above minimums, the installation of a transformer fire protection system should be considered. Some jurisdictions require combination of barrier and fire protection systems."

Subclause 4.4.2 of IEEE Standard 979, "IEEE Guide for Substation Fire Protection," states:

> "Transformers containing less than 2000 gal (7571 L) of insulating oil should be separated from buildings by the minimum distances shown in the following table:

Transformer Rating	Recommended Minimum Distance From Building*
75 kVA or less	10 ft (3.0 m)
76-333 kVA	20 ft (6.1 m)
More than 333 kVA	30 ft (9.1 m)

*Guidance for recommended minimum distances from buildings in electric generating plants are given in ANSI/NFPA 850-1992 [B31] and ANSI/NFPA 851-1992 [B32].

Where a transformer is installed next to a building with less than the minimum distance, the building should have fire-resistive wall construction. Guidance can be found in NFPA 255-1992 [B29], "Standard Method of Test of Surface Burning Characteristics of Building Materials."

Separation between large transformers

Subclause 4.4.3 of IEEE Standard 979, "IEEE Guide for Substation Fire Protection," states:

> "Large oil-filled transformers should be separated by at least 30 ft (9.1 m) of clear space and/or a minimum 1 hour fire-rated barrier."

For further recommendations regarding substation fire protection, including "Typical Oil Quantities in Equipment," refer to the IEEE Standard 979, "IEEE Guide for Substation Fire Protection," and NFPA 850-1992, "Recommended Practice for Fire Protection for Electric Generating Plants," especially where this NFPA code has been adopted by authority having jurisdiction. If any local code or ordinance is more restrictive than a recommendation listed in the NFPA code or the IEEE Standard, then the local code or ordinance should be followed.

If you like more information or have any question, please contact Mike Eskandary, Electrical Engineer, Transmission Branch, at (202) 720-9098 or at Mike.Eskandary@wdc.usda.gov.

The Case for Distribution Line Hardening

Extreme weather events such as ice storms, hurricanes and tornados are certainly not "new news" to RUS borrowers, but it seems that in recent years an increase in the frequency and magnitude of such events has been on the minds of nearly everyone. The damage to electrical facilities at distribution cooperatives alone has surpassed what many experts ever thought possible, and some cooperative members in severely affected areas have spent many long hours in the dark waiting for their electric service to be restored.

The aftermath of such scenes has raised many questions among utilities, customers, regulators, and other interested parties, and perhaps the most resounding question to be posed thus far has been, "What can be done to eliminate or at least help alleviate the damages caused to electrical facilities from extreme weather events?" This question alone has set the wheels of innovation and research into motion in a profound way to diligently search for an appropriate answer. Some cooperatives are finding at least part of the answer in a concept frequently referred to as Distribution Line Hardening (DLH).

DLH is a term that is now commonly being used in the industry to describe a process (and individual actions) in which utilities make changes and improvements to their electric facilities as a way of mitigating and avoiding damages from severe weather events. Some state authorities have promulgated rules which require jurisdictional distribution utilities to prepare and implement DLH plans as part of their normal operations, and many other utilities are engaging in such plans as well.

DLH is a concept whose time has fully come, and most experts expect that it will be an integral part of future activities aimed at improving reliability and enhancing the many benefits that will eventually be realized through other coming changes such as Smart Grid infrastructure deployment. DLH is considered by many utilities as a way of "getting their house in order" to show their concern for the customer and willingness to adapt their methods in order to improve reliability and service.

There are many actions that fall into the category of DLH, but experts warn that there are no "Silver Bullets" when it comes to completely avoiding utility storm related damages. Even though a company may give due diligence to preparation, some damages are inevitable – especially in extreme weather events. Despite this fact, most experts also agree that DLH can be an extremely valuable asset to utilities, and it can make a tremendous difference in reducing the damages that might be expected. Some of the more common DLH tactics that utilities are currently engaged in are:

- Increased right-of-way trimming and improved vegetation management programs
- Tree replacement programs
- Danger tree removal
- Improved sectionalizing schemes (Establishing reliability zones, etc.)
- Identification and replacement of deteriorated facilities
- Strengthening critical infrastructure
- Designing targeted facilities to exceed regulatory and/or NESC requirements
- Increased inspection and maintenance
- Improved guying and anchoring methodologies
- Deploying new technologies
- Placing more emphasis on joint-use attachments and compliance issues
- Placing more emphasis on proper engineering and construction practices
- Strategic conversion of overhead facilities to underground facilities when justifiable

One interesting caveat concerning the conversion of overhead to underground is the tremendous amount of research that has been completed in recent years on this subject. Several states have commissioned research projects and many other studies have been compiled as well. While the results of these studies are outside the scope of this article, it is interesting to note that thus far no state has required the wholesale conversion from overhead to underground. While there are several reasons for this, the tremendous costs and unimaginable logistical challenges of such conversions are the most important factors. Despite this fact, many authorities and utilities agree that there are special circumstances where smaller scale overhead to underground conversions would make sense and prove to be justifiable in terms of avoided destruction and costs.

If you would like more information or have any questions, please contact Steve Conover, Patterson & Dewar Engineers, Inc. (P&D) at 606-872-3501or at sconover@pdengineers.com. You may also visit the web-site at www.pd-engineers.com .

NESC Conclusion of Alternate Calculation Methods for Load and Strength Factors

As of July 31, 2010, alternative calculation methods using load factors of Table 253-2 and strength factors of Table 261-1B of the 2007 National Electrical Safety Cole shall no longer be applied. These alternate method tables were older calculations for wood and reinforced (not prestressed) concrete structures. The alternative method remained in the National Electric Safety Code to allow engineers who continued to use the old method time to implement the change over. Notification of the sunset date can be found in Rules 253 and 261 of the 2007 edition of the NESC. Tables 253-1 and 261-1A remain as the primary means of determining load and strength factors for Rule 250B (district loads), Rule 250C (extreme wind loads), and Rule 250D (extreme ice with concurrent wind conditions).

If you would like more information or have any questions, please call Gabrielle Stokes, Electrical Engineer, Transmission Branch, at (202) 720-1924 or at Gabrielle.Stokes@wdc.usda.gov.

Horizontal Post Non-ceramic Insulators for Transmission Lines

RUS is currently reviewing applications to Technical Standards Committee 'A' for accepting non-ceramic horizontal post insulators for transmission lines. The accepted insulators will be listed in Information Publication 202-1, LIST OF MATERIALS Acceptable for Use on Systems of USDA Rural Development Electrification Borrowers. The evaluation guidelines for the insulators are given below:

1. Insulators are to comply with ANSI C29.17-2002, American National Standard for Insulators—Composite—Line Post Type or ANSI C29.18, 2003 American National Standard for Insulators—Composite—Distribution Line Post Type. The insulators will be accepted with clamp end fittings and a rigid curved base or bendable curved base for use with round poles and a rigid flat or bendable flat base for flat surface poles. The pole mounting bracket should accommodate 7/8 inch bolts spaced 12 inches apart. Footnotes will be added to manufacturers that offer a two hole blade end fitting.

2. Clamp dimensions are to comply with ANSI C29.7, Porcelain Insulators-High Voltage Line-Post Type

3. For each voltage class, the insulators meet the following:

   Insulators mounted on wood and fiberglass poles (rigid curved base or bendable curved base)

Voltage kV	ANSI Class (Design Type)	SCL (Ult. Strength), lbs	Min MDCL Lbs
34.5	51-34	2400	1200
46	51-35	2400	1200
69	51-36	2400	1200
115	250-54*	2650	1325
138	250-60*	2300	1150
138	250-66*	2000	1000

*Note: 2.5 inch rods

Insulators mounted on steel and concrete poles (rigid flat or bendable flat base for steel poles or rigid curved base or bendable curved base for centrifugally spun concrete poles)

Voltage kV	ANSI Class (Design Type)	SCL (Ult. Strength), lbs	Min MDCL Lbs
34.5	51-36	2400	1200
46	51-36	2400	1200
69	250-41*	3300	1650
115	250-60*	2650	1325
138	250-66*	2300	1150
138	250-75*	2000	1000

*Note: 2.5 inch rods

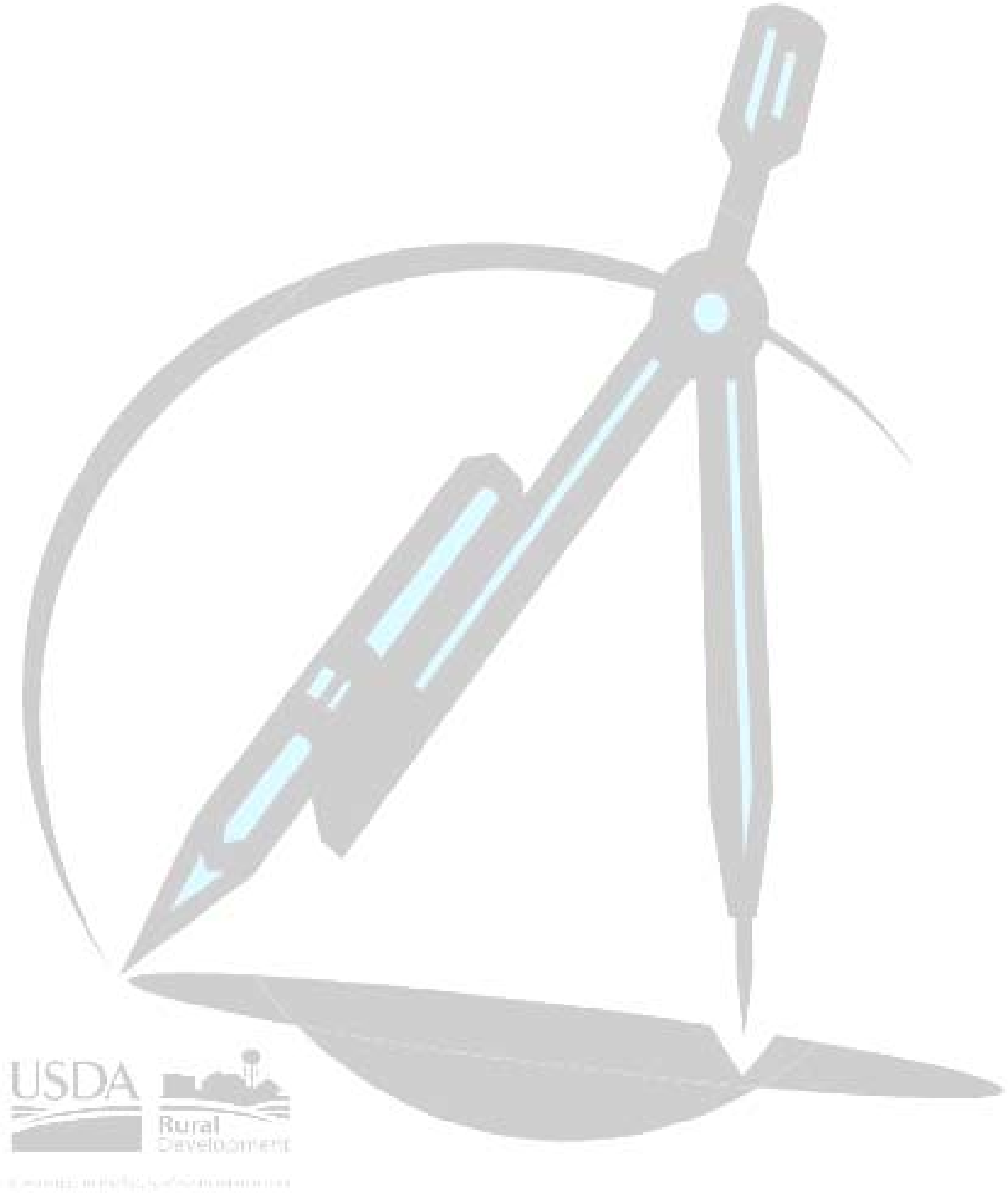
4. For each voltage class, the insulators with 3.0 inch rods are to meet the following:

   Insulators mounted on steel and concrete poles (rigid flat or bendable flat base for steel poles and rigid curved base or bendable curved base for centrifugally spun concrete poles)

Voltage kV	ANSI Class (Design Type) See note below	SCL (Ult. Strength), lbs	MDCL lbs
115	250-60	4500	2275
138	250-66	3900	1950
138	250-75	3500	1750

Note: Since ANSI C29.17 does not include horizontal posts with 3.0 inch diameter fiberglass rods, the design types in this table are given for reference to minimum and maximum lengths, minimum CIFO and 60 Hz Flashover Values

If you would like more information or have any questions, please contact Donald Heald, Transmission Branch, at (202) 720-9102 or Don.Heald@wdc.usda.gov.



OPERATIONS AND MAINTENANCE

Idle Services

The report of Idle Services on the Form 7, Part B, is completely inaccurate for many RUS borrowers. Often it is a figure simply carried forward year after year and not considered important. Consequently many electric systems erroneously report a high number of idle services on the Borrower Statistical Profile. According to RUS Bulletin 1717B-2: The number of idle services in Column b should be the total number of delivery points to which service wires remain physically in place but for which no bill is being rendered. Seasonal consumers or patrons paying a nominal sum for the retention in place of idle facilities should be excluded from the count of idle services.

This is a review of a cooperative which has 19,000+ consumers and reports over 3,000 idle services on their Form 7. A printout of inactive accounts revealed numerous old accounts, many over 10 years old, still on the books as idle services. In a typical example a consumer moved out, another consumer moved in and was given a new account number; but the old account was not retired and the old account number was not deleted from the system. Other examples include houses or barns which were torn down long ago and the services removed but not retired. The result is a large number of accounts reported as idle services which are long gone, and the idle services and total services in place are overstated.

Economic impacts of idle services include: increased maintenance expense, increased liability exposure, stranded plant, possible line losses, increased depreciation expense. Property taxes may also be affected (varies from state to state).

Solution: Give the inactive printout to the servicemen to review and correct every account. Each serviceman knows his area well and many accounts can be checked without even leaving the office, however most will have to be physically checked in the field enroute to other jobs or a rainy-day job. This will obviously take a long time because it is not a high priority. Then revise the report and December Form 7 with a footnote explanation. In the future the report of idle services can be kept up to date with GIS and proper retirement procedures. There are 2 separate issues to address: 1) correct the report of idle services, and 2) physically remove idle services in the field.

One cooperative brought in all transformers that had not been active for 6 months – several hundred transformers – most of which went back into inventory. Recommendation: flag 12 months and let the servicemen use judgment if they know of a location where somebody might be moving back in reasonably soon. Note: this did not correct the report of idle services. It still takes the process discussed above to produce an accurate report.

Remember, all numbers reported on the Form 7 are supposed to be accurate and certified by the manager. The report of idle services may be more important than you think and should be as accurate as possible.

If you would like more information or have any questions, please contact Mike J. Norman, GFR (IN, KY, TN) – Northern Regional Division at Mike.Norman@wdc.usda.gov.

NERC Reliability Update

The era of mandatory compliance to grid reliability standards began in June 2007. Presently, there are fifty (50) Generation & Transmission cooperatives and approximately one hundred and fifteen (115) distribution cooperatives included on the North American Electric Reliability Corporation (NERC) Compliance Registry. These registered entities are responsible for compliance to over ninety (90); Federal Energy Regulatory Commission (FERC) approved reliability standards.

NERC has issued penalties for one or more violations to hundreds of utilities and it is expected that many more penalties, will be issued throughout 2010. A majority of the violations discovered in the early stages of the program where assessed as $0 penalties, however, financial **penalties issued range from $1,500 to $25 million.** Sixteen cooperatives have received financial **penalties ranging** from **$1,500 to $125,000.**

To date, cooperatives represent approximately 11.7 % of the total number of violations. The top violated standards for cooperatives are **PRC-005** - Transmission and Generation Protection System Maintenance and Testing, **CIP-001** - Sabotage Reporting, **TOP-002** - Normal Operations Planning, **PRC-008** - Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program, and **CIP-004** - Cyber Security - Personnel & Training. Of the CIP-001 violations, 92 % are mitigated.

Since PRC-005 is the standard most violated by cooperatives it is important to understand its purpose, applicability and the actual violations. The purpose of this standard is "to ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested". It is applicable to entities registered as Transmission Owners, Generator Owners and Distribution Providers that own a transmission Protection System. From the NERC Glossary of Terms a Protection System is defined as "protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry".

The violations of PRC-005 include the following:

- The cooperative failed to:
  - document procedure for testing DC control circuitry

- provide evidence of having a Protection System maintenance and testing program for all types of Protection Systems
- provide summary of maintenance and testing procedures
- provide basis for intervals in program

- The cooperative did not:
  - have a Protection System Maintenance and Testing Program for its newly installed Protection System
  - notify reliability entities of relay or equipment failures
  - coordinate changes to its protection systems as required by the standard
  - maintain and test within the defined intervals

It is critical for cooperatives that are included on the NERC Compliance Registry to understand the requirements of the reliability standards associated with its functional registration. Non-compliance can subject a registered entity to financial and other types of penalties. Additional information about reliability standards, violations and penalties are available on the NERC website (http://www.nerc.com).

If you have any questions, please contact Patti Metro, Manager, Transmission and Reliability Standards, National Rural Electric Cooperative Association at 703-907-5817 or at patti.metro@nreca.coop.

ENVIRONMENTAL

SPCC Plan Template for Tier I Qualified Facilities Now Available from EPA

As you know, NRECA pushed very hard to have EPA streamline the requirements for Spill Prevention, Control and Countermeasure (SPCC) plans as they apply to small facilities like substations. We worked with other small business representatives through the SBA to help EPA develop a template that companies could use to satisfy the SPCC requirements. As we announced in earlier memos, EPA issued final amendments to the SPCC regulations in the Federal Register at **73 F.R. 74307 (December 5, 2008)** that addressed "Tier I Qualified Facilities". The amendments included a template that those facilities could use instead of having to draw up an individual plan. The final amendments did not become effective, however, until January 14, 2010. While these regulations are now finally effective, the template was only available by making paper copies of the forms contained in the December 5, 2008 Federal Register publication.

In response to requests from NRECA and other groups, EPA has now made the SPCC plan template available in a form that can be filled out electronically and they have just posted it on their webpage at: http://www.epa.gov/emergencies/content/spcc/tier1temp.htm. This should make it much easier for small co-operatives to avail themselves of the streamlined SPCC requirements.

If you would like more information or have any questions, please contact Jim Stine at 703-907-5739 or at james.stine@nreca.coop.

RENEWABLE ENERGY & SMART GRID

RUS Funding of Smart Grid Projects

The concept of Smart Grid has taken off recently (i.e. the past 2 years). With the advent of ARRA funding via Department of Energy's (DOE) "Smart Grid Investment Grants" and Smart Grid Demonstration Projects" programs, RUS seeks to supplement the cooperatives' plans by providing funding for those cooperatives that received grants and also those who did not. The idea of a smarter grid is nothing new to the rural cooperatives community as this type of infrastructure has been used for more than 10 years. Cooperatives have been deploying Automated Meter Reading (AMR), Automated Metering Infrastructure (AMI) and Supervisory Control and Data Acquisition (SCADA) systems to better serve their membership as well as improve efficiencies within the system. So, cooperatives are well ahead of the curve on Smart Grid.

RUS is providing funding for Smart Grid infrastructure projects. Approval authority lies within the Regional Offices, Northern Regional Division (NRD) and Southern Regional Division (SRD), with the materials/equipment review being handled by Electric Staff Division (ESD). For the short term, these projects are being handled as a "non-standard materials/equipment" basis. The goal is to eventually have more of the associated equipment added to IP 202-1 List of Materials. In fact, some of the metering associated with smarter systems is already included in the List of Materials.

The following are some preliminary items that should accompany an application for Smart Grid project funding:

- CWP or Amended CWP
- Overall scope of the project
- Cost/benefit analysis (similar to that of AMR/AMI)
- Technical information on the proposed equipment
- Itemized list of the proposed equipment, including number of units and unit cost

If you would like more information or have any questions, please contact Norris Nicholson, Chair – Technical Standards Committee "A" (Electric) at 202-720-1979 or at Norris.Nicholson@wdc.usda.gov.

ADMINISRATIVE AND OTHER

RUS Bulletins 1728F-810 and 1728F-811

RUS Bulletins 1728F-810 and 1728F-811, Electric Transmission Specifications and Drawings for 34.5 kV through 69 kV and 115 kV through 230 kV is currently under revision. The revision updates the written part of the construction specifications. The drawings will be in AutoCAD format and include a new assembly drawing and a new guide drawing.

RUS is in the process of accepting non-ceramic horizontal post insulators for transmission lines with voltages 34.5 kV to 138 kV. As such, there will be a horizontal post assembly unit for non-ceramic insulators added to the drawings. There will also be guide drawing for setting depths of multiple pole structures.

Because the revised document will need to go through the Federal Register process, the projected date for the document to appear on the RUS website is not clear.

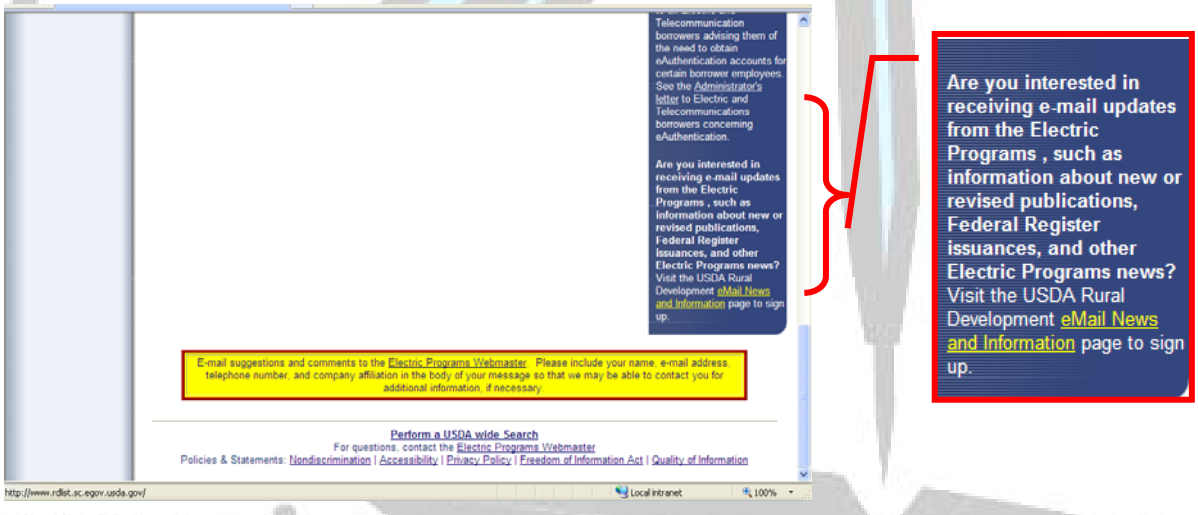
If you would like more information or have any questions, please contact Donald Heald, Transmission Branch, at (202) 720-9102 or Don.Heald@wdc.usda.gov.

Electric Programs News by Email

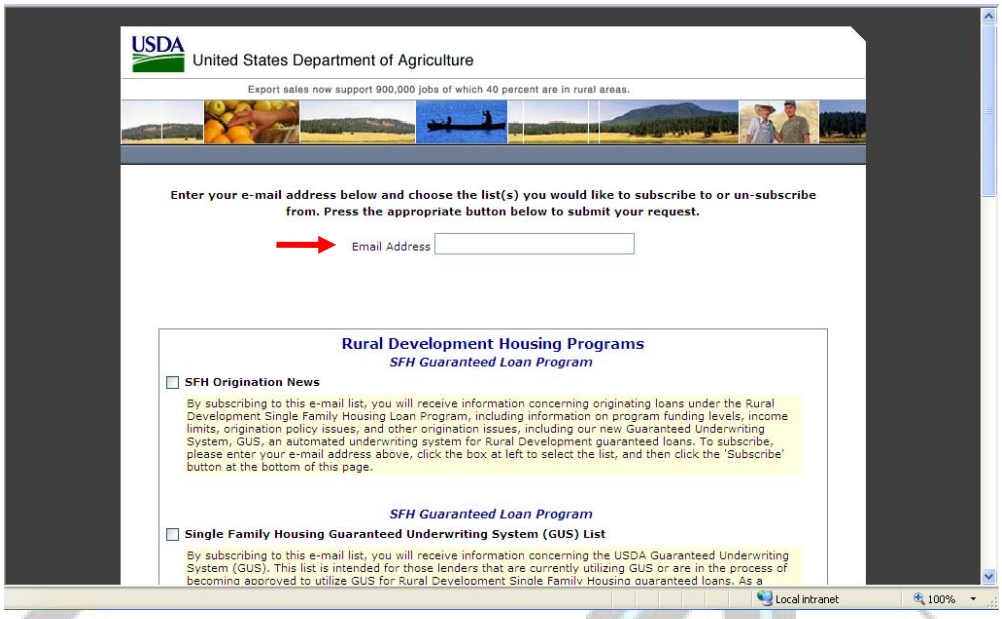
Borrowers and other interested parties are able to receive RUS Electric Programs news and updates by joining our mailing list. By signing up for the mailing list, borrowers shall have access to new and revised publications, Federal Register issuances, and more.
To receive updates, simply follow the step-by-step instructions below.

1. Go to http://www.usda.gov/rus/electric/index.htm
   Notice the **News Spotlight** border to the right of the screen.

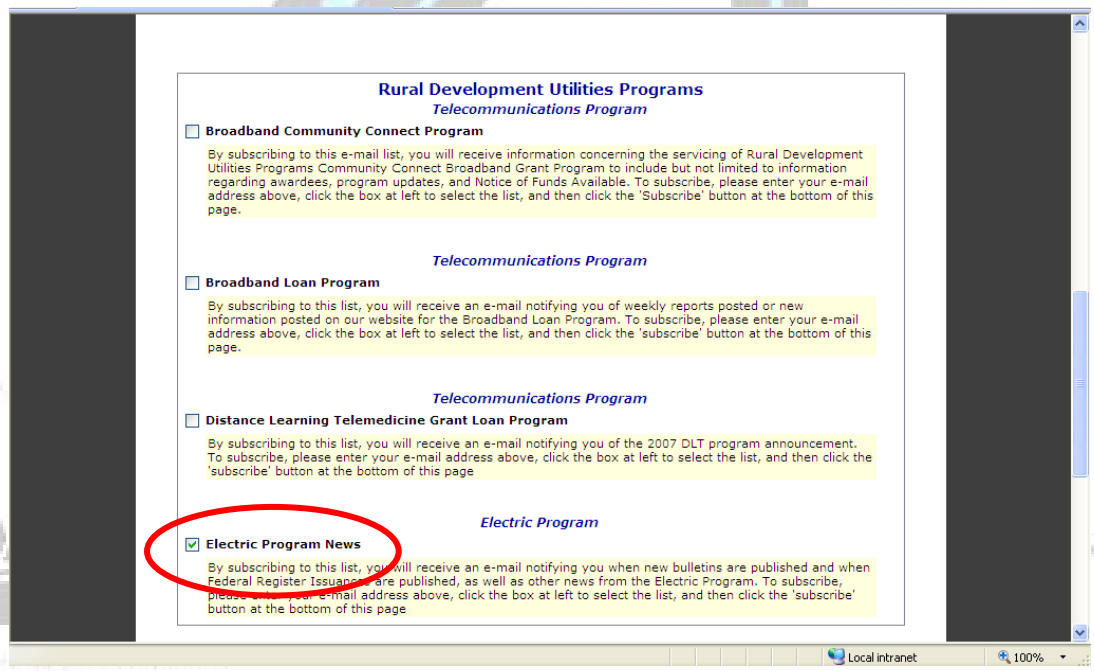
2. Scroll to the bottom of the page. Notice the announcement, "Are you interested in receiving email updates from Electric Programs…" Click the **eMail News and Information** link.



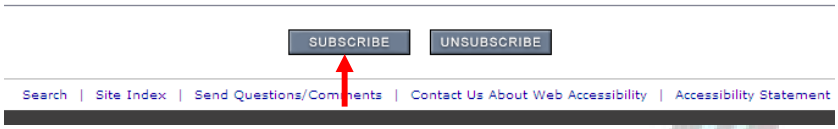
3. You will be redirected to the following page. Insert the desired email address where you would like to receive Electric Programs updates.



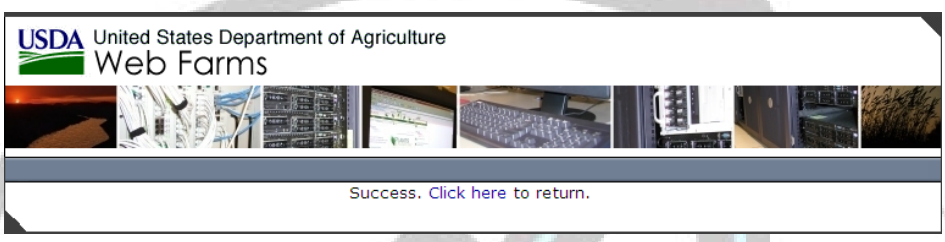
4. Scroll down to the **Rural Development Utilities Programs** section and select **Electric Program News** check box under **Electric Program**



5. Scroll to the bottom of the page and press **SUBSCRIBE**.
   Attention: You will be redirected to the same page, please repeat steps 3 through 5.



6. After you have successfully subscribed, you will be redirected to the following page for confirmation. The system will then send a confirmation email.



The RUS website is undergoing updates; appearance is subject to change.
If you would like more information or have any questions, please call Gabrielle Stokes, Electrical Engineer, Transmission Branch, at (202) 720-1924 or Gabrielle.Stokes@wdc.usda.gov.

Exhibit 1

Time Schedule for the Next Revision of the National Electrical Safety Code

The revision schedule for the 2012 NESC is as follows:

September-October 2010	Period for NESC Subcommittee Working Groups and NESC Subcommittees to reconsider all recommendations concerning the proposed amendments and prepare final report.
15 January 2011	Proposed revision of the NESC, Accredited Standards Committee C2, submitted to NESC Committee for letter ballot and to ANSI for concurrent public review.
15 May 2011	NESC Committee approved revisions on the NESC submitted to ANSI for recognition as an ANSI standard.
1 August 2011	Publication of the 2012 Edition of the NESC.

You can find detailed NESC information on IEEE's NESC website: http://standards.ieee.org/nesc/index.html .

APPENDIX A

RURAL UTILITIES SERVICE ELECTRIC STAFF DIVISION

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Vacant	Secretary		(202) 720-0980

APPENDIX B

NRECA TRANSMISSION & DISTRIBUTION ENGINEERING COMMITTEE

Member	Organization	Location
T&D Executive Committee		
David Mohre, **CHAIR**	NRECA	Arlington, VA
Overhead Distribution Lines Subcommittee		
Clive Buttrey	Middle Tennessee EMC	Murfreesboro, TN
James Byrne	Poudre Valley REA	Fort Collins, CO
Titus (Ty) Diamond	Flint EMC	Warner Robbins, GA
L. Allan Glidewell	Southwest Tennessee EMC	Brownsville, TN
Robby Hamlin	CoServ Electric	Corinth, TX
Tom Hoffman	Agralite EC	Benson, MN
Chad Kirkpatrick	Fort Loudoun EC	Vonore, TN
Kevin Mara	GDS Associates, Inc.	Marietta, GA
Gerard Moore	RUS	Washington, DC
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